Section 1

Report of Philip K. Verleger, Jr.
Regarding MMS Proposed Rule for Valuation of
Crude Oil Lease Production
May 27, 1997

The Minerals Management Service (MMS) has issued proposed regulations that link the royalty payment for oil taken from federal leases to futures prices reported by the New York Mercantile Exchange. Specifically, MMS proposes to use the average "settlement price" for the "nearby" futures contract for a given month as the base price used to determine the value of oil taken from a lease. MMS apparently believes that these prices represent a superior measure of value to transaction prices in the producing field, which have been used traditionally.

However, in preparing the draft regulation the MMS erred. Futures prices do not provide a dependable measure of the contemporaneous value of volumes of oil being actually delivered to buyers, even in markets away from the field. Instead, futures prices can be distorted by a large number of factors including changing perceptions of risk, activities of speculators, and trader expectations of future events such as wars, droughts or other factors.

Futures prices also provide an inappropriate basis of the price willing buyers would pay for oil in the producing field. These amounts (values) can and often do vary widely from field to field and from the value at a market center such as Cushing, Oklahoma due to unique conditions that influence supply and demand factors at the point of sale.

MMS is also mistaken that the NYMEX index it has selected accurately reflects the prices paid by willing buyers and sellers on the futures market even if one accepts the principle that the NYMEX provides a satisfactory starting point for the valuation of crude. The MMS proposes to use the "settlement price" from the NYMEX. The settlement price is computed from transactions that occur during the last two minutes of trading.[1] Trading through open outcry on the NYMEX floor lasts from 9:45 am to 3:10 PM (5 hours, 25 minutes). Further, after-hours trading occurs through NYMEX's proprietary computer system, ACCESS, from 4 PM on one day to 8 am on the following day, Sunday night through Friday to allow traders in Asia and Europe to use the market during their normal business hours.[2] Thus, in a given week, trade on the NYMEX can occur in 104.08 of the 168 available hours during the week. MMS proposes to use trades that occur in only ten minutes of the 104.08 hours, literally 0.16 percent of the time in which the market is open.[3]

MMS also errs in using a simple average of daily transactions during a month. Activity in markets will vary over the course of a month with the volume of purchases and sales peaking around scheduling or delivery day. Data from the New York Mercantile Exchange frequently reveal a much larger number of transactions occur towards the end of the month. Data from companies' physical transactions also show that the most trades in market centers such as St. James or Cushing occur in the 72-hour period prior to scheduling. Thus, use of a simple weighted average of all transactions during a month creates a biased estimate of the price willing buyers and sellers would want to use.

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1 The NYMEX rules use the weighed average price of all trades occurring during the last two minutes to determine the settlement price of a contract that has more than ten percent of outstanding open interest except on the expiration day for a contract. On the expiration day, the NYMEX uses the weighed average of all trades occurring during the last thirty minutes of trading.

2 Access trading starts at 7 pm on Sunday night.

3 The market is open from 7 pm est on Sunday to 8 am Monday through ACCESS, 13 hours. The market is then open from 9:45 am to 3:15 pm for trading on the following on Monday, 5 hours and 25 minutes. The market is then open from Monday afternoon at 4 pm to 8 am Tuesday Morning through Access, 16 hours. This process continues until the market closes at 3:10 pm Friday.

Finally, MMS is also mistaken to rely on prices quoted by *Platt's* or other publications to determine differentials between the NYMEX prices and the prices in a market center. Prices published by Platt's and other organizations are labeled "assessments." These assessments are gathered by reporters who call traders to obtain information from traders as to prevailing prices. Research has shown that these assessments are less reliable than arm's-length transactions between willing buyers and sellers.

I. The Role of Futures Markets

While futures markets have fulfilled an important function in commerce for centuries,[4] the particular function of futures prices is frequently misunderstood. Observation reveals that nearby futures prices can, under a variety of circumstances, vary from *prices being paid in cash markets*. Extraordinarily complicated and esoteric models have been developed to demonstrate the causes of the differences. The fact remains, however, that scholars, practitioners, traders, and investors acknowledge that futures prices differ from the prices a willing buyer will pay a willing seller for a unit of commodity meeting all the specifications of the futures contract in the cash market today.[5]

Peck (1985, pp. 73) provides a succinct summary of the role of futures markets:

> "Although futures markets have become the primary pricing markets for many commodities, they have not replaced either spot or forward markets. Both remain important in the marketing of commodities and are *the primary*

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[4] See Williams (1982 or 1986), Hieronymus (1980) or Peck (1985).

[5] Among the factors that explain the difference are the time value of money, speculation, and risk premia. A very incomplete list of articles that discuss these factors would include Anderson (1983), Beck (1993), Brennan (1958) and (1991), Chang, Cho and McDougall (1990), Deaves and Krinsky (1995), Frankel (1987), French (1986), Kolb (1992), Williams (1986), and Walton (1991).

means by which ownership is actually transferred from producers to processors and consumers." {emphasis added}

Peck continues. "Futures markets are widely used to complement fundamental purchase and sales prices."

Futures markets provide a mechanism by which a producer can sell units of a commodity for future delivery through a clearing house and buyers can purchase units of a commodity for future delivery thorough the same organization. To facilitate trade the unit is standardized in terms of specification. While the seller may plan on ultimately offering a unit that has certain unique characteristics and the buyer may want a specialized unit, both will use futures markets to "hedge" their positions because the price prevailing on the futures market is correlated with the price of the unit that they will ultimately deliver. Note that the term correlated does not imply that the futures price today equals the price that the seller will ultimately receive. Nor does the term correlated mean that the futures price today is the price the buyer will actually pay. Rather, the term correlated implies that the price in the futures market converges towards the price that will be paid or received at a specific delivery location. Further, the term correlated implies that any large changes in the physical market will be reflected at least partially in changes in the futures price.

Central to the difference between cash prices and futures prices is the term "expected future cash price." Futures prices reflect current market expectations about what cash prices will be at some time in the future. (Edwards and Ma, pp. 164). The expectations will depend on a term that has become known as the "risk premium." Risk premiums represent the difference between "the expected spot price and the prevailing futures price" for delivery at the same time. (Edwards and Ma, pp. 169.)

The term "risk premium" has the sound and feel of an economic phrase that is designed to confuse. The term has had that effect whether or not that was the intent. However, the idea is terribly critical and has an important bearing on the proposed regulation. Thus, a brief exposition is required. As described by almost every review, the risk premium is defined by the simple equation

Futures price = Expected price in the future +/- risk premia.

Edwards and Ma assert that futures prices quoted today (for example, the price quoted on May 18, 1997 for delivery of crude oil in July 1997) will equal the expected cash price in the future (the cash price that will be paid for crude delivered in July 1997) if, and only if, the risk premium is zero. (Edwards and Ma, pp. 170). Edwards and Ma also suggest that this condition is highly unlikely.

The existence of a risk premium has important implications because the existence of a risk premium implies that futures prices will not be unbiased predictors of future cash prices. Put another way, the existence of a risk premium implies that use of futures prices will either result in underpayment or overpayment to royalty owners if futures prices are substituted for arm's-length cash prices even assuming that other differences (such as transportation, quality, risk and other differences) can be addressed.

The measurement of risk premiums has been the subject of a large number of studies. Most of these studies have focussed on currency markets.[6] Most of these studies have also identified the existence of a risk premium, meaning that currency futures prices do not provide an unbiased predictor of future exchange rates.

Chang (1985) examines the data for several agricultural products and confirms the existence of a risk premium. Chang also tests for the ability of large speculators to achieve superior results and finds that this group of traders has realized better returns. This success of speculators has important implications which will be noted below.

Kolb (1993) examines data for twenty-nine commodities for the period from 1957-1988. He concludes that most commodities exhibit no risk-premium. However, risk-premiums are identified for heating oil and crude.

Moosa and Al-Loughani (1995) conduct a test of the relationship between cash and future crude oil prices for the period 1986 to 1991. They conclude that speculation affects prices and appear to confirm the existence of a risk premia.

Deaves and Krinsky (1995) examine the variation of risk premia over time. For crude oil and three other commodities they confirm the existence of a risk premium but conclude that it varies over time.

Dominguez (1989) finds the peculiar absence of a risk premium in long term futures contract (six month futures contracts) but concludes that shorter term

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6 Frankel's 1993 book provides an excellent survey of the subject. Section III (pages 185 to 262) focusses on the question "Is there an exchange risk premium."

futures contracts overreact to news.

On balance, then, the academic research appears to conclude that a risk premium exists for the energy complex and particularly in the crude oil market. However, this conclusion would seem to be moderated by the fact that the period of coverage of most of the research ended in 1991 or 1992. There is relatively little published research that encompasses the experience through 1996 when markets appear to have reached maturity. Further research is required to determine the nature, status and behavior of the risk premium for crude oil.

This absence of published research is, however, offset by studies by various investment banks, which have asserted that investors could earn substantial returns by investing in commodities. The research materials circulated in support of these appeals all confirm the existence of a risk premium in oil.

Professor Froot of the Harvard Business School has, for example, written a long paper for Goldman Sachs demonstrating the existence of a risk premium in crude oil. (Froot, 1993). Goldman Sachs has continued to emphasize this fact in reports issued to clients and in public relations releases since. Goldman Sachs' competitor J.P. Morgan advanced a similar conclusion in a 1995 report.

The persistence of a risk premium in commodities and especially oil is explained by the excess of selling over buying hedgers. In English this means simply that there are more traders who use futures markets for commercial purposes who want to sell than there are traders who want to buy. Since the number of sales must always equal the number of purchases, this requires that another group of traders called speculators must generally hold an offsetting long position. The consequence is the risk premium.

The role of speculators is important in the formation of futures prices, and especially oil prices. Verleger (1996) explains the economic motive driving speculators. Kraples (1997) asserts that speculators play a particularly important role in the determination of oil futures prices. Kraples notes

> "Speculators, such as commodity funds, move in and out of the oil markets for reasons that may have nothing to do with oil - for example, because a trading program has noted a historical propensity for oil to move one way when pork bellies move another. It is possible that a sudden decline in the demand for paper barrels - occurring because one or more large players suddenly decides to abandon oil as a financial instrument - cause a decline in paper oil prices that quickly reduces the value of physical barrels." (Kraples, 1997 pp. 22).

Kraples presents a table which shows that the correlation between speculative positions and oil prices has increased over time. For example, the correlation from 1986 to the present is only 0.02. For the interval from 1994 to the present, though, the correlation is 0.72.

While others take a more moderate view,[7] the fact remains that fluctuations in speculative positions do drive prices on futures markets. Daily summaries of activity on commodity markets frequently note that prices were pushed higher or lower by speculative trading. The commodity page of the *Financial Times* will, for example, describe on almost a weekly basis how trading by hedge funds has affected price levels of futures in metals or oil.

In summary, then, futures prices differ from cash prices. The difference is explained by the risk premium in the market. This premium fluctuates over time

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[7] For example, Drolas at the Center for Global Energy Studies has presented results that suggest that speculators are only following market trends.

and is influenced by the activity of speculators and other events. As a consequence, futures prices reflect both conditions of contemporaneous supply and demand and expected conditions of supply and demand. They are not indicators of what a willing buyer would pay a willing seller in the market today for supplies of the commodity delivered today.

II. Locational Differences

Substitution of NYMEX and market center for local, freely negotiated arm's-length prices between willing buyers and sellers also unfairly denies the buyer savings that may result when unique conditions depress prices below prices at the market center. Such conditions are a familiar feature in commodity markets. For example, farmers are often unable to receive higher prices that prevail in a market center if their local grain elevator is full. Under such circumstances one often reads that grain must be stored on the ground and exposed to weather until a sufficient number of freight cars can be obtained. The farmers delivering the last volumes lose out.

The same situation can occur in oil markets when a local refinery is forced to shut down for repairs or the pipeline that moves crude from the field to the nearest market is disrupted. In such circumstances, the price offered for crude in the field may be substantially less than the price offered in the market center.

Prices offered in the field may also not increase with prices in the market center if supplies to the market center are disrupted. The disruption of a major pipeline or shipping artery can cause prices in the market center to rise while prices in the field remain unchanged or fall. Precisely such an event occurred in early April 1997 when the Canadian Interprovincial Pipeline (IPL) was forced to reduce shipments due to severe weather in Canada. Prices in Cushing were pulled up as refiners sought immediate supplies of oil.[8]

Disruptions of this type occur randomly over the course of the year. A review of several years issues of *Platt's* or the *Petroleum Argus* reveals that such disruptions occur fairly frequently.

III. Manipulation

Futures markets have long been vulnerable to manipulation. Markham (1987 and 1991) provide a comprehensive survey of both the history of manipulation in commodity futures markets and the futility of attempts to regulate it. Williams (1995) offers a detailed examination of one of the most famous incidents of manipulation of a commodity futures market: the Hunt silver crisis of 1980.

One manipulation of futures markets described by Markham (1991) demonstrates the increased risk created by the use of futures markets to set oil royalties. In this episode two purchasers of potatoes in Idaho, Messrs. Taggares and Simplot, sold large numbers of contracts in Maine potatoes on the New York Mercantile Exchange (NYMEX). The purpose of the sales was to drive down the price of Maine potato futures because Messrs. Taggares and Simplot had entered into contracts to purchase potatoes in Idaho based on the futures contract. Their sales thus reduced the cost of purchasing Idaho potatoes. Having achieved their goal

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8 Cite to Platt's when the publication arrives.

Simplot and Taggares ultimately defaulted on their obligations on the NYMEX by failing either to close their positions or take delivery[9]

Commodity markets for crude oil, while relatively new, have been subjected to various types of manipulation. Verleger (1987) explains how the introduction of the Petroleum Revenue Tax by the government of the United Kingdom caused producers in the North Sea to accelerate trading in cash and forward markets. Mabro et. al. (1986, 1993) provide further details on the operation of the government taxation scheme and its effect on prices. Barrera-Rey and Seymour (1996) describe frequent squeezes in the market for Brent crude and explain the structure of the market that lends its self to easy manipulation. Barrera-Rey and Seymour also describe the economic incentives that cause traders to manipulate the market today.

Notwithstanding claims of its proponents, the NYMEX crude market is not immune to manipulation. Markham makes it clear that the Commodity Futures Trading Commission is almost powerless to deter attempts to manipulate futures prices. Pirrong (1994) suggests that the agency will be unable to prove manipulation until the Commodity Futures Act is amended to define manipulation.

In the current situation the evidence indicates that the substitution of settlement prices from the NYMEX for arm's-length cash prices will increase the exposure of royalty owners to manipulation and loss of revenue.

Futures markets are also relatively small and thus can be affected by apparently small transactions. Verleger (1996) notes that purchases of 180,000 futures contracts (180 million barrels of oil or three days of world consumption) by

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9 See Markham (1991) pp. 334-338, Markham (1987) pp. 83, and Leist v. Simplot 638 F.2d 283 (1980).

the German firm Metallgesellshaft led to a $ 4/bbl decline in the price of oil. Traders from Lehman Brothers made a presentation at a seminar sponsored by the state of Alaska that a forward sale of 30 million barrels (500,000 barrels a month) would depress prices on the NYMEX by $1.50/bbl despite the fact that this sale would represent less than 0.02 of daily world production. (Lehman Brothers, 1995).

IV. The Settlement Price

The choice of the settlement price is a mistake. Settlement prices are computed at the end of trading in a given day and represent only a small share of total trade. NYMEX procedures use the weighted average of all transactions that occurred during the last two minutes of trading except on the last day of trading in a contract. On the last day of trading NYMEX procedures require the use of the weighted average of all transactions during the last thirty minutes of trading.[10]

Trading in NYMEX contracts can occur during 104.08 hours during any week in which there are no holidays. Assuming a contract is the spot contract for approximately 20 days or four weeks the total number of hours that a contract trades as a spot contract is 424.32 hours. Only 1.13 hours of this trading period (0.3 percent of total trading time) is sampled in the determination of settlement prices.

It should also be noted that traders have frequently been accused of manipulating settlement prices for their own purposes. Barrera-Rey and Seymour (1996) report that dated Brent crude cargo prices are manipulated by traders in

[10] Note that the last day of trading is the day on which a contract expires. For example, trading in the April 1997 crude contract expired on March 20, 1997. Thus on March 20, 1997 the settlement price was computed using a weighted average of all trades that occurred over a period of thirty minutes.

European markets. Markham (1991) describes in detail problems experienced by the CFTC in other futures markets.

V. Daily Trading Patterns

MMS is also mistaken to use a simple weighted average of trading over a month. The volume of transactions in both the futures and the spot market increases as a contract approaches expiration. The calculation should reflect this pattern of trading.

VI. Use of the Spot Price

The use of the NYMEX futures price is also wrong because the spot price reference for the NYMEX is a forward price, not a spot price. While the futures price converges on the spot price at Cushing reported by price reporting services (*Platt's*, *The Petroleum Argus*, other) these reported spot prices are forward prices. For example, the *Platt's* cash price is the price that will be paid for oil to be delivered in the next month. (*Platt's*, 1996). This often may not reflect purchases in the field.

Cushing prices reported by *Platt's* are not representative of current prices. The *Argus* (*Petroleum Argus*, 1996) reports:

> The bulk of cash WTI trade at Cushing is conducted during *Platt's* 30-minute pricing window, which falls between the close of regular Nymex trading hours and the start of daily Access trade. These deals are widely acknowledge to be done to influence *Platt's* assessments. In order to provide a more accurate end-of-the-day picture, *Argus* assesses its crude prices two hours later each day. Cash WTI trade is also more active towards the end of each month in the three-business-day interval between the expiry of the prompt Nymex futures contract and pipeline scheduling.

In summary, *Platt's* and *Argus* report forward, not spot prices. The prices reported are not the price that would be paid by a willing buyer for crude delivered today by a willing seller. There are few reports of such prices in market centers. However, transactions between willing buyers and willing sellers occur every day in the field.

VII. Summary

NYMEX settlement prices cannot be used to measure the price a willing buyer will pay a willing seller in the field for several important reasons. First, NYMEX prices represent futures prices on forward prices - not futures prices on cash prices. There is, in fact, really no contemporaneous spot market for crude in the United States pipeline market at Cushing. Second, the risk premium in futures prices makes futures prices an inappropriate measure of cash prices. Third, futures markets can and have been manipulated successfully. Finally, settlement prices are measured during a small fraction of the trading period.

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Section 2

Comments of Benjamin Klein on Proposed MMS Crude Oil Royalty Regulations

I. Qualifications

1. I, Benjamin Klein, am a Professor of Economics at the University of California, Los Angeles (UCLA), a position I have held since 1978. In addition, I am President of Economic Analysis Corporation, which provides economic consulting services to law firms, corporations and government agencies. My particular areas of specialization are the economics of contracts, industrial organization and antitrust policy. I have published a wide range of articles in these areas, some of which have been published internationally, in such places as Europe, South America, Russia and China. A list of my publications is included in my resume in Appendix A.

2. In addition to my teaching responsibilities at UCLA, which consist of undergraduate and graduate classes in the economics of contractual arrangements and antitrust economics, I have taught classes on economic analysis for practicing antitrust attorneys and for United States Federal Judges. I also have held visiting appointments at the University of Washington, the National Bureau of Economic Research and the University of Chicago Law School. I have received numerous awards and honors and my research has been cited extensively. I currently serve on the Board of Editors of the *Journal of Law, Economics and Organization*, the *Supreme Court Economic Review*, the *Journal of the Economics of Business*, the *Journal of Corporate Finance* and *Managerial and Decision Economics*. I am also a member of the Board of Directors of the Center for Research On Contracts and the Structure of Enterprise at the University of Pittsburgh.

3. I have been retained as a consultant by various government agencies, including the Antitrust Division of the U.S. Department of Justice, the New Zealand Treasury, the U.S. Federal Reserve Board of Governors and the U.S. Federal Trade Commission Bureaus of Competition and Consumer Protection. I have given expert economic evidence in various proceedings both in the United States and abroad. Several of these engagements have dealt extensively with the

economics of crude oil markets in California. I recently analyzed the application of the existing MMS royalty regulations to Texaco's federal lease fields in California for the period of 1988-1996. I have also consulted extensively on West Coast crude oil markets in several engagements involving ANS crude oil. A complete list of my prior economic testimony is included in my resume in Appendix A.

II. Introduction and Summary

A. Summary of the MMS methodology

1. The MMS's proposed "netback" methodology can be summarized as follows:

Royalty value of crude at the lease = Average NYMEX futures contract settlement prices (East of the Rockies) or average Alaska North Slope spot prices at market center (West of the Rockies)

Less one or more of the following adjustments :

1) Quality/location differential between index pricing point and market center using spot prices of reference crudes (East of the Rockies)
2) Quality/location differential between market center and aggregation point using spot prices of reference crudes (East and West of the Rockies)
3) "Actual" Transportation costs (East and West of the Rockies)

As described below, each of these adjustments is likely to be subject to substantial errors. It is highly unlikely that the resulting royalty values will be more accurate measures of the value of the crude at the lease than actual transactions that occur there.

B. Overview of problems with the proposed methodology

1. The proposed regulations would introduce a large amount of uncertainty, error, and compliance cost into the royalty valuation process in an attempt to address a "problem" that has not been established to exist. (Undervaluation of royalty basis prices.) Even when a vertically

integrated producer sells its crude in arm's-length sales at the lease, the MMS advocates that we completely ignore this clear information about market value and should instead try to infer the value of the crude with a convoluted and arbitrary procedure which is virtually certain to produce errors.

2. For example, the proposal to maintain constant differentials between different crudes for a year at a time makes no economic sense. Relative crude prices can and frequently do change substantially even over short periods of time. Similarly, the use of "actual costs" to adjust for transportation will overstate the value of many crude oils in the field because it substantially understates or in some cases completely ignores a variety of costs and risks that vertically integrated firms incur when moving crude from the field to downstream locations. The resulting discrimination against vertically integrated production and transportation firms will reduce the incentives for many of these firms to make efficient downstream investments.

3. Because of these and other problems with the proposed methodology, actual transactions at the lease are likely to provide far more accurate and reliable royalty values than the "netback" methods proposed by the MMS.

4. Some of the points discussed below are most relevant to the California crude market with which I am most familiar. Others apply to all areas.

III. The Proposed Methodology will not Adequately Adjust for Differences in Quality and Economic Characteristics between Crude Oil Fields

A. There are substantial quality differences between fields

1. The State of California has one of the most diverse indigenous crude supplies of any region in the world. California crudes range from heavy (e.g. 13 degrees API) crude oils, sometimes with high levels of sulfur and other impurities, to light crudes (e.g. 40 degrees API)

with relatively few impurities. The major crude oil producing regions in California are illustrated in Figure 1 along with the percentage of total state production from each area. The qualities of the different crude oils produced and marketed in these different areas varies substantially, both within and across the regions. Some specific examples of this variation are shown in Table 1 which lists the API gravity and sulfur content of several fields in each region of the state. The API gravity of a crude oil is a measure of its weight with lighter crudes having higher API gravities. Gravity is one of several important measures of crude oil quality and is a frequently used shorthand statistic for ranking crudes because it affects the amount of relatively high valued light products a refiner can make with the crude. Higher gravity crudes yield larger quantities of gasoline and other light products than heavier crudes.

2. As shown in Table 1, in the region with the largest production in California, the San Joaquin Valley, crude oil gravities range from the heavy crude fields such as Midway-Sunset and Kern River fields with API gravity of 13 degrees to light crude fields such as Elk Hills and Guijarral Hills at 35 degrees and Cal Canal at 40 degrees. Similarly, in the L.A. Basin crude fields range from Newport and Huntington Beach at 15-21 degrees to Rosecrans and Los Angeles Downtown at 34-38 degrees.

3. Another important difference in the quality of many California crudes is their sulfur content. Several federal lease fields, such as Beta (3.36% sulfur) and Point Arguello (4.3% sulfur), are offshore fields with very high sulfur levels. High levels of sulfur are generally undesirable in crude oil because of the corrosive effect of sulfur on refining equipment and because its presence in petroleum products causes air pollution problems. California, in particular, has very stringent regulations concerning the level of sulfur in petroleum products for air quality reasons.

4. California crudes differ substantially in many other characteristics besides gravity and sulfur as well. Typical crude oil assays report information on a large number of crude characteristics such as distillation yields, vanadium, nickel, pour point, nitrogen, Reid vapor pressure, smoke point, freeze point, cloud point, asphaltenes, and so on.

Figure 1

Major Crude Oil Producing Regions in California

Region	Estimated 1994 Production (bbl/day)	Percent of State Production
Los Angeles Basin	111,771	11.8%
Santa Maria/Salinas/Cuyama Basin	29,797	3.2%
San Joaquin Basin	608,157	64.4%
Ventura Basin	34,557	3.7%
Federal (OCS)	159,543	16.9%
Total	943,925	**100.0%**

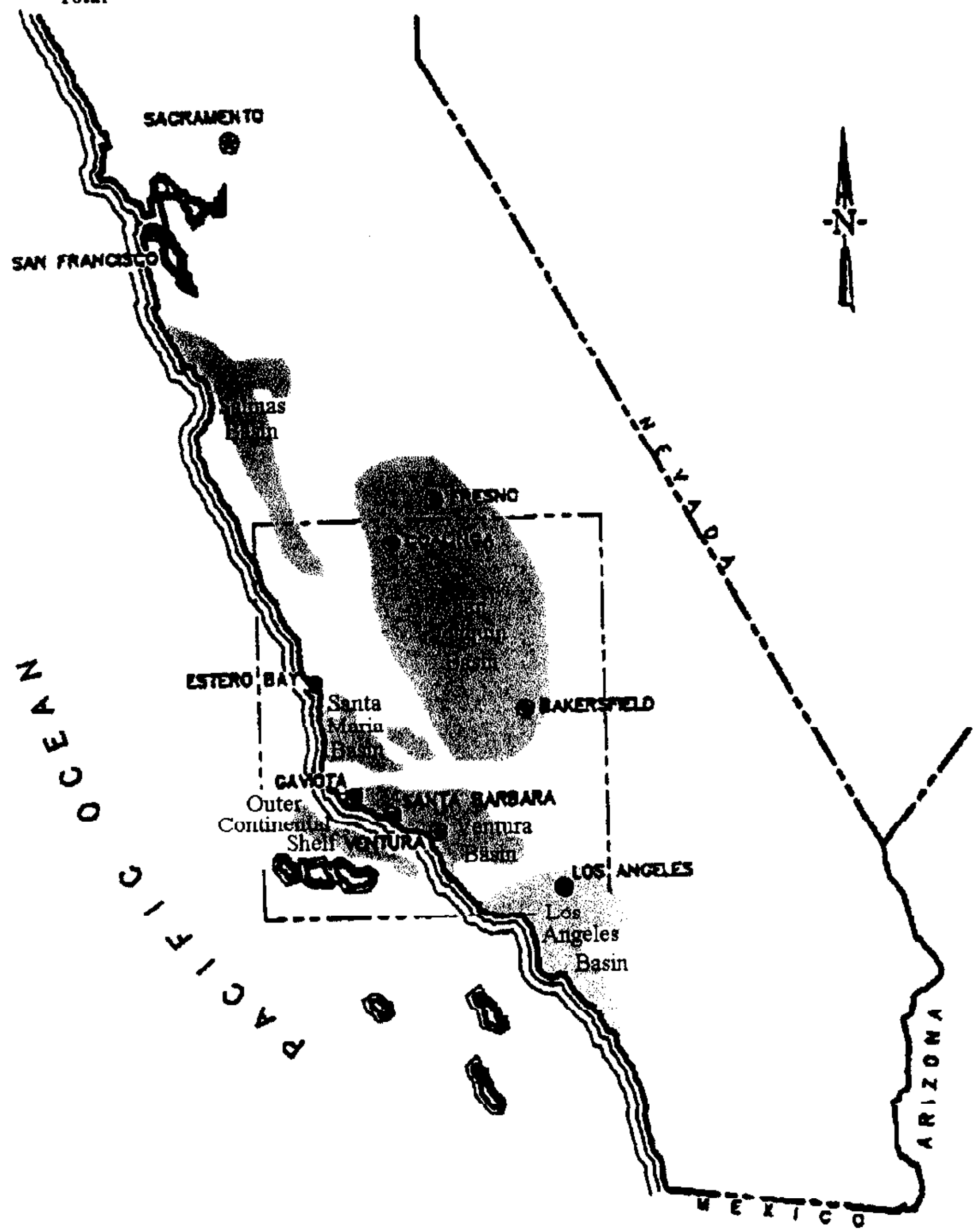

Table 1

Examples of the Variation in California Crude Quality

Field	Gravity	Sulfur
Los Angeles Basin		
Newport	15.0	3.62
Wilmington	17.5	1.63
Long Beach Area	19.0	1.49
Huntington Beach	21.1	1.65
Santa Fe Springs	31.0	0.47
Rosecrans	34.0	0.58
Los Angeles Downtown	38.0	0.33
San Joaquin Basin		
Midway-Sunset	13.0	1.22
Kern River Area	13.1	1.21
South Belridge Heavy	14.0	1.19
South Belridge Light	30.5	0.46
Yowlumne	30.7	0.61
Guijarral Hills	35.0	0.67
Elk Hills	35.1	0.40
Lost Hills	38.0	0.15
Cal Canal	40.0	0.26
Santa Maria Basin		
Casmalia	9.0	2.61
Cat Canyon	12.0	4.49
Santa Maria	13.0	5.90
Lompoc	21.0	3.50
Orcutt	25.0	2.10
Ventura Basin		
Placerita	12.0	2.07
Aliso Canyon	16.0	1.43
Ventura	27.8	1.10
Rincon	28.0	1.41
South Mountain	32.0	0.91
Santa Susana	36.0	0.07
Outer Continental Shelf		
Beta	14.8	3.36
Point Arguello	19.0	4.30
Dos Cuadros	26.0	1.11

Source: Texaco and U.S. Department of Energy Bartlesville Project Office Crude Oil Analysis Data Bank

B. There are substantial economic differences among fields

1. In addition to the enormous variation in quality, different crude oil fields in California are also subject to widely divergent economic influences depending on such factors as the quality of the crude, the supply and demand for different types of crude and the capabilities of local refiners in each region, the distance from the field to potential buyers, and the transportation alternatives available from each field. Some California crudes are refined in the same region they are produced, others are shipped long distances to refineries in other parts of California or in other states.[1] Some crudes, such as relatively light, low sulfur crudes, can be processed economically by a large number of different refiners. Others, such as very heavy crudes or crudes with high sulfur levels, are most economically processed by refineries with specialized refining equipment such as cokers, catalytic crackers, and hydrotreating facilities that can upgrade the crude into light products such as gasoline.

2. California crudes also differ with respect to the number and cost of their transportation alternatives. Some crudes could potentially be sold to many different buyers due to their location or their potential access to multiple pipelines. Others have relatively few transportation alternatives and must be moved via one or two pipelines or even trucked to a relatively small number of potential buyers. Still other crudes are moved to their final disposition via many different combinations of pipelines, tankers, trains, tanker trucks and other means. The physical characteristics of a crude can also affect its transportation alternatives. Many heavy crudes, for example, are transported most economically in heated pipelines or by blending with lighter crudes. Because of this wide variety in the number and cost of transportation alternatives, and differences in the number and types of potential buyers for the crude from any particular field, California crudes have very different economic characteristics.

[1] For example, the All American Pipeline carries a blended stream of California crudes (including some federal lease crude) to Texas.

C. The differences in quality and economic characteristics are reflected in substantial price differences between fields.

1. Because of these substantial differences in crude quality and economic characteristics, the prices of California crude oils vary widely from field to field. Figure 2, for example, shows a scatter plot of the 1995 posted prices of 115 different crude fields in California against the gravity of the crude oil. The prices range from lows of $9 to $10 per barrel for heavy, high sulfur coastal crudes such as Santa Maria and Cat Canyon up to $16 to $17 for lighter crudes such as Edison Light, Helm and Cal Canal. In addition, Figure 2 also shows that large variation in prices exists even for crudes within a relatively narrow gravity range. For example, in the gravity range of 22 to 26 degrees crude prices range from a low of $11.21 to a high of $15.02. As shown below, similar types of variations are found in crude oil spot market prices. This large variation in the posted and spot prices of California crudes illustrates the importance of the economic factors discussed above for the determination of California crude prices. These data illustrate that the MMS proposal to accurately capture all of this variation with three spot prices and a set of exchange differentials which is only updated annually makes no economic sense.

IV. The MMS's Attempt to Rely on Spot Prices and Ignore Contract Prices is Misguided.

1. The large majority of crude oil volumes in California (and throughout the world) are sold under term contracts rather than one time spot sales.[2] Given the fact that spot markets in crude oil tend to be thin, and the high cost of holding inventories to protect against supply disruptions, it is typically impractical for refiners to rely solely on spot purchases to supply their refineries.

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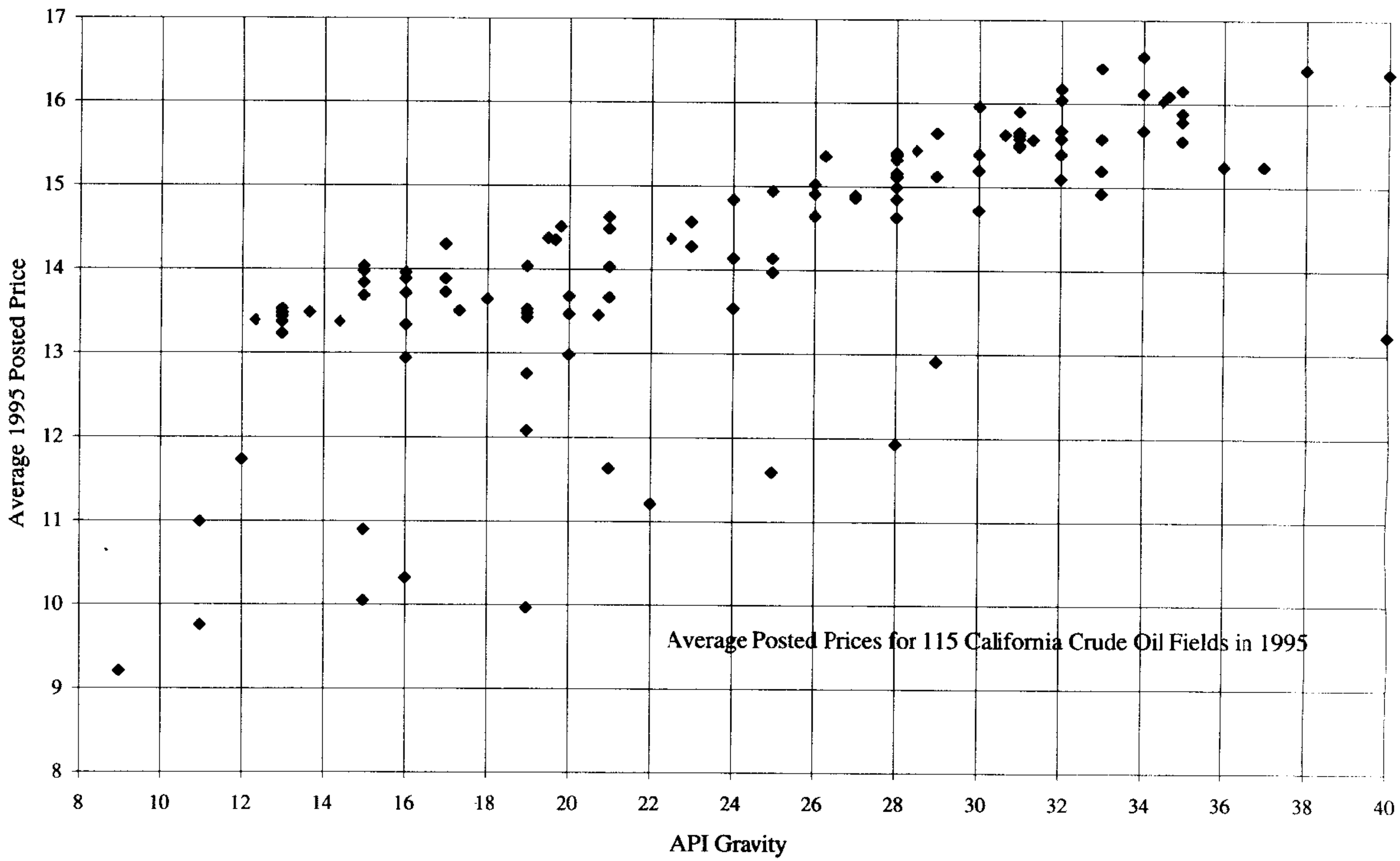
[2] For example, a 9/88 GAO report states "Generally, most oil transactions involve long term contractual agreements based on posted prices; however, the spot market involves oil resellers and brokers who supply oil on a onetime basis. Spot market sales occur, for example, when a buyers normal supply has been interrupted and the buyer needs extra barrels for special purposes." GAO, "California Crude Oil, An Analysis of Posted Prices and Fair Market Value," p. 28.

Figure 2

The Differences in Quality and Economic Characteristics of California Crude Oil Fields are Reflected in Crude Prices



Source: 1995 Posted price bulletins for Chevron, Unocal, Texaco, Enron, Mobil and Koch.

For these and other reasons, refiners generally contract for their base crude supplies under term contracts and use the spot market primarily for sporadic small purchases and sales due to unanticipated events such as supply disruptions or refinery outages.

2. In fact, there are only three California crudes with publicly reported spot prices: Kern River, THUMS, and Line 63. In contrast, there are many fields with widely varying qualities and market values. It would be impossible to accurately replicate all of the variation in actual crude prices with only three spot prices plus the annual data on exchange differentials that the MMS proposes to collect.

A. Market conditions can differ significantly between spot and term sales.

1. The differences in the underlying economic and market conditions between spot and term crude oil transactions can lead to significant price differences. Such price differences also reflect the underlying contractual obligations of the parties. Term contracts generally restrict the actions of the parties to the contract in one or more ways. For example, the buyer in a term contract is obligated to take the contractually specified volumes of crude for a minimum specified period of time. This obligation prevents the buyer from opportunistically ignoring its purchase obligations in order to take advantage of short run opportunities that might arise to purchase crude on favorable conditions in the spot market. This assured demand for its crude is valuable to the seller since it knows it will not be required to cut production or incur other costs while it searches for alternative buyers for the crude. For this reason the seller may be willing to accept a somewhat lower price for its crude in a term sale than in a spot sale. Similarly, the obligation of the seller to deliver the contractual quantities for the term of the contract is valuable to the buyer since it helps ensure that it will have the crude necessary to run its refineries at optimum levels and will not be forced to engage in costly search for alternative supply sources. The relative values that crude buyers and sellers place on reducing these kinds of supply and demand disruptions affects the prices that we observe in term contracts vs. spot sales.

2. Significant differences between spot and term prices are not unique to crude oil markets. Many markets for commodities and industrial goods involve both spot and term transactions. Economic research on these markets shows that spot and term prices can differ for a wide variety of reasons including: a) the market's expectations about the path of future prices, b) the relative "risk aversion" of the contracting parties, c) the extent to which a seller's production costs correlate with movements in the industry supply curve, (spot prices may insure seller vs. cost uncertainty -- when costs are high, prices will be high), d) the extent to which the buyers value correlates with movements in the industry demand curve (spot prices may insure buyer against changes in the industry demand curve -- e.g. crude price will be low when product prices and, hence crude values, are low), and e) the relative importance of demand vs. supply shocks in determining industry prices.[3]

3. In addition, the MMS proposal to rely solely on spot prices implies that many crude producers will face increased risk. In particular, crude producers that sell crude on a term basis and pay royalties on a spot basis will face increased risk.

4. The proposed rule completely reverses the relative reliance on contract vs spot prices that exists in the current regulations. Spot prices are currently near the bottom in the hierarchy of valuation benchmarks. In contrast, the proposed rule makes contract prices virtually irrelevant and spot (or futures) prices are the only thing that matters.

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[3] See, for example, R. Glenn Hubbard & Robert J. Weiner, "Long Term Contracting and Multiple-Price Systems, *The Journal of Business*, Volume 65, No. 2, April 1992; and A. Mitchell Polinsky, "Fixed Price versus Spot Price Contracts: A Study in Risk Allocation", *Journal of Law, Economics & Organization*, Volume 3, No. 1, Spring 1987.

V. The Proposed Method of Using Exchange Differentials to Adjust for Quality and Location Differences between Crudes would Result in Large Valuation Errors for Many Crudes.

1. The proposed method to keep the price differentials between crudes constant for a year at a time would result in large valuation errors for many crudes. Crude price data show that market differentials between different crudes often change a great deal during a year. For example, Figures 3-4 illustrate the large changes in prices between the MMS's proposed reference crude in California, ANS, and the few California crudes for which spot price data exist. Figure 3 shows the difference between the spot prices of ANS and Kern River during 1990-1996. ANS is approximately 28-30 degree crude and its price is reported for deliveries in LA. Kern River is heavy (13 degree API) crude whose price is reported for deliveries in the San Joaquin Valley. Hence, movements over time in the price spread between these crudes reflect changes in demand for heavy vs light crudes, locational factors, changes in the general level of crude prices, and other factors. The price spread between these crudes varies over this period from a high of about $9 per barrel in 1990 to roughly $2 per barrel in late 1993 and mid 1995.

2. Obviously, the MMS's proposed assumption that the differential between these crude prices can reasonably be held constant for a year at a time makes no sense. Over the period graphed in Figure 3 this procedure would have resulted in an average error in valuing Kern River crude of approximately $.89 per barrel. For 1996 the average error would have been $1.54 per barrel. Valuation errors of this magnitude would introduce a large element of uncertainty into the valuation process and create essentially arbitrary windfall gains and losses.

3. These significant price swings between ANS and California crudes frequently occur even for crudes with relatively similar gravities to ANS. Figure 4 graphs the difference between ANS and Line 63 crudes. Line 63 is a blended stream of heavy and light San Joaquin valley crudes with an API gravity of approximately 28 degrees, which is very similar to ANS. The reported spot price is for deliveries at Hynes station in Los Angeles. Even though their gravities are very similar, the price spread between these crudes has changed significantly over this period, ranging

Figure 3
Monthly Difference Between ANS and Kern River Spot Prices

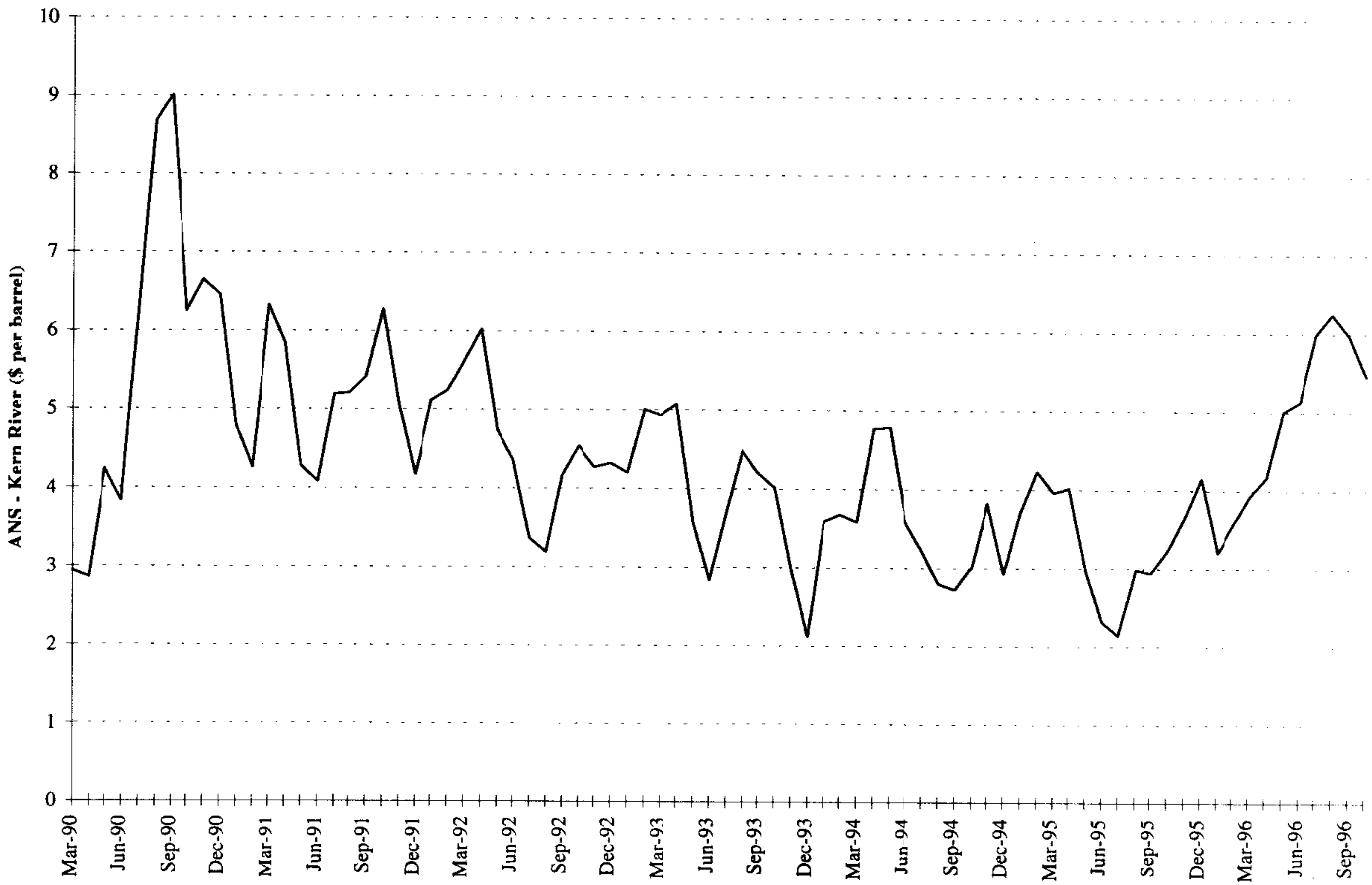


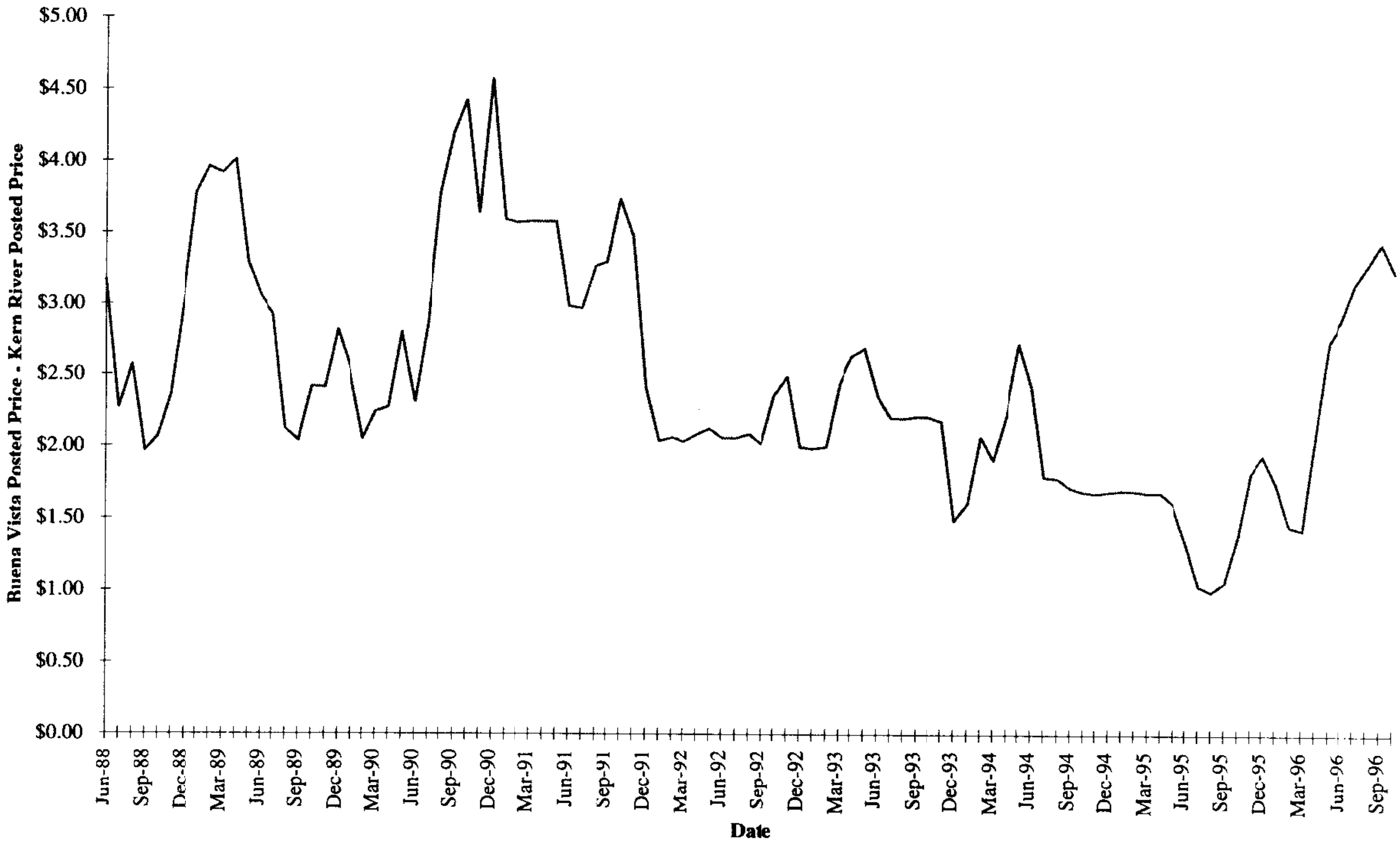
Figure 4
Monthly Difference Between ANS and Line 63 Spot Prices

from a high of more than $2.40 per barrel in March of 1992 to a low of less than $.25 per barrel in February of 1991 and March of 1994.

4. In addition to the large changes in relative prices between ANS and California crudes there are also large changes in relative prices of different California crudes. These price changes reflect changes in the forces of supply and demand for different types of crude and crudes in different locations. For example, Figure 5A shows the difference between the posted prices of two federal lease crudes in the San Joaquin Valley, Buena Vista (at 26 degrees API) and Kern River (at 13 degrees API). The price spread between these crudes has changed dramatically over the period 1988 to the present as the supply and demand for heavy vs. light crudes and other factors have changed over time. The price spread ranged from a high of $4.58 per barrel in February of 1990 to a low of $1 per barrel in August of 1995. Figure 5B shows a similar graph of the difference between Ventura Avenue at 28 degrees and Buena Vista at 26 degrees. Even though these two crudes have very similar gravities, their relative posted prices still change significantly over time. For example, Buena Vista was generally posted at a premium to Ventura which reached as high as $.45 per barrel during 1988 through 1993 but was posted at discounts of up to -$.11 per barrel during 1994 and 1995.

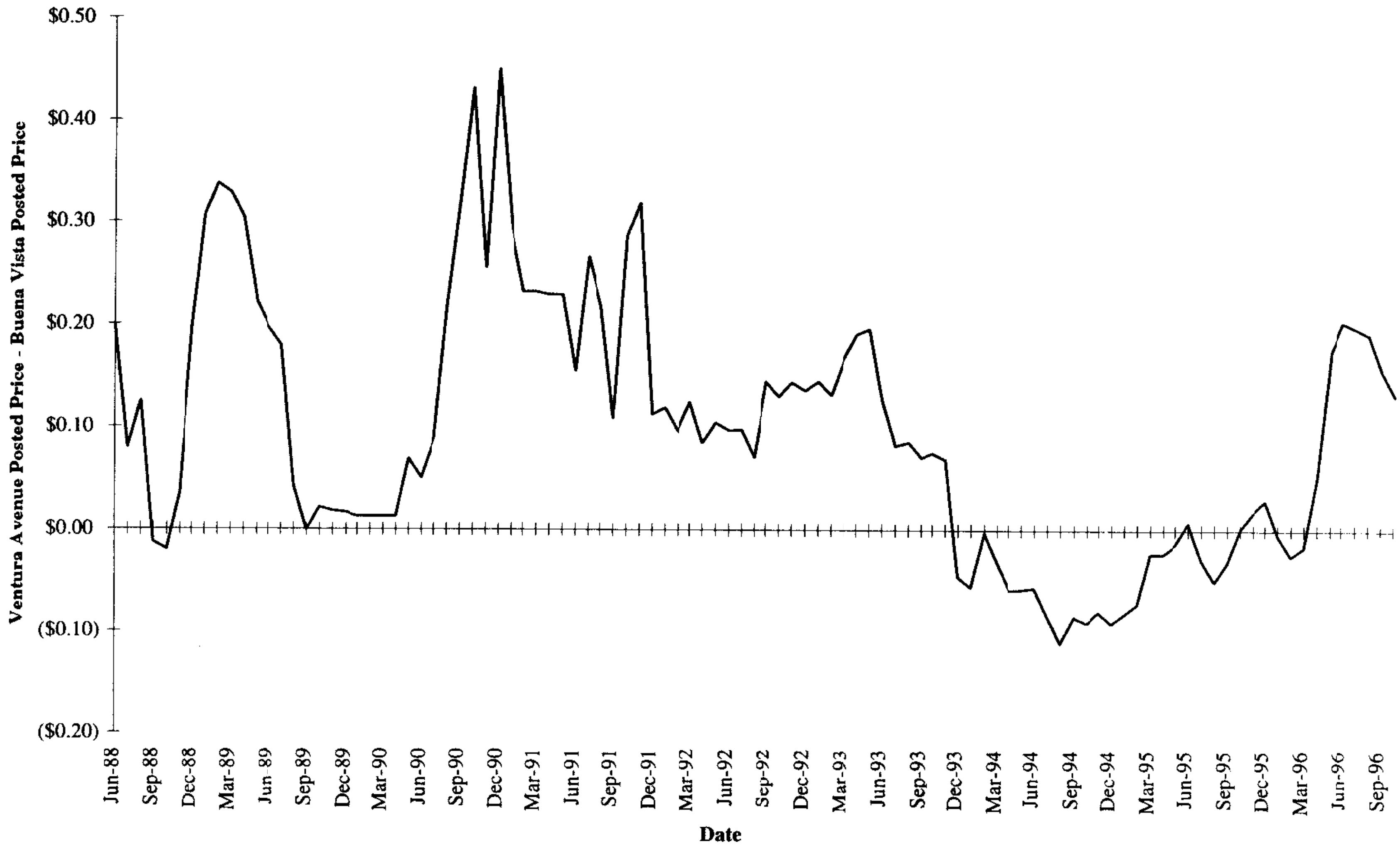
5. A third example of the variation in relative California crude prices over time is shown in Figure 5C which depicts the difference between Kern River and one of TEPI's federal offshore crudes, Point Arguello. Even though Point Arguello is a somewhat lighter crude at 19 degrees than Kern River at 13 degrees, it is posted at a substantially lower price. This reflects the high levels of sulfur and other undesirable characteristics of this offshore crude and the high costs incurred to transport Point Arguello and other OCS crudes to refining centers. The premium of Kern River over Point Arguello varies substantially over the period from 1991 to the present from a high of $4.27 per barrel in November 1991 (when Point Arguello production began) to a low of $2.60 per barrel in December 1994.

Figure 5A
Difference Between Buena Vista and Kern River Posted Prices



Source: Posting bulletins for Buena Vista and Kern River

Figure 5B
Difference Between Ventura Avenue and Buena Vista Posted Prices



Source: Posting bulletins for Ventura Avenue and Buena Vista

Figure 5C
Difference Between Kern River and Point Arguello Posted Prices

Souce: Posting bulletins for Kern River and Point Arguello

6. The large changes in relative crude prices between ANS and California crudes, and among different California crudes confirms that the MMS's proposed royalty methodology will result in large valuation errors.

7. There is an internal inconsistency in the MMS proposed methodology. On one hand, MMS argues that spot prices should be used because they better reflect market conditions than contract prices. On the other hand, they propose keeping price differentials between crudes constant for an entire year at a time which would significantly reduce the extent to which the MMS value estimates reflect crude market conditions.

8. It is likely there will not be a significant volume of transactions for the MMS to publish reliable quality/location differentials for many crude oils. In addition, small sample sizes for particular crude combinations may be problematic since individual differentials will frequently reflect a variety of transaction specific factors such as size, availability of transportation alternatives, etc., e.g., it makes no economic sense to assume that a small producer of crude would be able to negotiate the same transportation terms on a particular pipeline as Chevron.

VI. The Rule that Integrated Companies with their own Transportation Assets will be Treated Differently from Certain Independent Companies Makes No Economic Sense.

1. The MMS proposal that the actual proceeds received by crude producers in arm's-length sales should be disregarded as long as the producer is an integrated company, or is an independent company that has also purchased one barrel of crude in the last two years makes no sense. It is another example of a rule that introduces a large amount of error and uncertainty into the royalty valuation process in an attempt to avoid a potential problem that is highly improbable. The MMS appears to assume, without support, that dealings among producers, including buy/sell and exchange agreements, are used to avoid royalty payments. That is, they argue that prices in actual arms length transactions cannot be relied on because crude oil sellers

may be willing to accept below market prices if they can recoup some of their loss in a corresponding purchase transaction. This theory is highly dubious even when applied to individual buy/sell agreements. It makes absolutely no sense when taken to this extreme and applied to the entirety of a companies crude oil transactions.

2. For example, most crude oil producers will not be completely balanced in their overall crude oil purchases and sales. How would a company that sells 10,000 barrels per day and purchases 5,000 per day ensure that it comes out whole in this hypothetical price manipulation scheme? Even more problematic, purchases and sales with individual trading partners will not typically be in balance. If Texaco is a net seller of crude oil to Shell and a net buyer from Exxon, it obviously cannot underprice the crude sold to Shell in the hope that Exxon will similarly underprice the crude it sells to Texaco. There simply is no credible theory or evidence that crude oil producers do not attempt to get the highest price possible in the crude oil sales. Throwing out the best evidence available on the value of federal lease crude in the field, actual arm's-length sales prices, on the basis of such an implausible theory makes no economic sense.

3. Another reason the MMS theory is so implausible is because it implies that the terms of each crude oil sale would have to be tailored very specifically to the individual transactors depending on what other transactions the seller has with each company. For example, if Texaco was selling Kern River crude to Chevron and Exxon, the MMS theory seems to imply that the prices of the Kern River crude would have to differ depending on Texaco's net purchase or sale position on all other crudes to each buyer. In addition, every time Texaco entered into a new sale or purchase contract with a particular party the MMS theory implies that it would then have to re-negotiate all of its existing contracts with that party in order to keep the relative benefits of the hypothetical mispricing scheme in balance.

4. Based on my knowledge about the crude oil industry and my analysis of many crude oil sales contracts in many different situations, I find this theory completely implausible. Sellers of crude oil typically seek to negotiate the highest possible price in each transaction. The types of wholesale price manipulation envisioned by the MMS are completely implausible.

5. In sum, the price manipulation theory suggested by MMS provides an extremely weak basis for throwing out the best available information about the value of crude in the field: the prices in arm's-length sales. In addition, crude producers that sell a significant portion of their production in arm's-length sales at the lease should be permitted to use these prices to value the remainder of their production.

VII. The MMS Theory that Buy/Sell Transactions Do Not Reflect Market Values of Crude is Incorrect.

1. The MMS argues that all exchange and buy/sell transactions should be excluded from royalty calculations because the parties to a buy/sell could agree to both underprice their crudes by a common amount and, hence, reduce their royalty payments. Under this view the losses incurred by each party in selling their crude at the low price are exactly offset by the gains from buying the other parties crude at the same low price.

2. This theory is clearly not correct as a matter of economics under a wide variety of circumstances. For example, the theory requires not only that the contract prices of all of the crude oils involved in a particular trade are understated, but that they are all understated by exactly the same dollar amount per barrel. If this is not the case, the party delivering the crude which was underpriced by a larger amount would be giving away value and, therefore, would not want to do the trade on the basis of the contract price.

3. Even if we accept (for sake of argument) the MMS claim that prices used in buy/sell exchange transactions are understated, it seems totally incredible that all crudes in California would be understated by exactly the same amount. The data displayed in Figures 3-5 above showed that California crude prices vary tremendously both across fields and over time. These data indicate that the assumptions underlying the MMS theory are inconsistent with actual California crude prices.

4. In addition to the requirement that all of the crudes involved in a given trade are underpriced by the exact same amount at the time the contract is signed, the MMS view that buy/sell agreements have no economic consequences also implies that the relative underpricing of the crudes will remain constant over the life of the contract. This seems highly unlikely given that many buy/sell contracts are in effect for significant periods of time and because relative prices of different crudes in California change dramatically even over relatively short periods. As shown above in Figures 5A-5C, for example, the posted prices of federal lease crudes frequently change substantially relative to each other even over relatively short periods. These price movements can and do create substantial wealth changes. Relative price changes of this magnitude contradict the MMS theory that buy/sell agreements based on, for example, posted prices have no economic impacts on the trading parties.

5. In addition, the MMS theory for excluding buy/sells clearly does not apply to buy/sell transactions with unequal volumes traded or to transactions where one of the crudes is valued on a basis that is different from the other crude. Even under the MMS theory that all crudes are underpriced equally, buy/sells with unequal volumes would be equivalent to outright sales (or purchases) for the difference in volumes. In addition, the MMS theory would fail for transactions in which TTTI traded California crude at one price benchmark (e.g., Kern River posted price) for some other crude which was valued on some other benchmark, such as a spot price. Such trades clearly would meet the opposing economic interest requirement in the current regulations even under the MMS's new theory about what this term means. In addition, even if there were relatively few of these transactions, that would be sufficient to validate the use of the same benchmarks for a much broader set of transactions.

VIII. The Use of "Actual Costs" to Account for Transportation Costs in Many Situations is Likely to Overstate the Lease Value of Many Federal Lease Crudes Because It Ignores or Understates Many of the Costs Incurred and Value Added by Downstream Operations.

1. In general, it is very difficult to value correctly crude oil in the field based on the prices of transactions that occur downstream, such as the spot trades at aggregation points or market centers that the MMS proposes to use for valuation. In these types of downstream sales there are typically substantial costs incurred and value added by downstream location/availability, transportation, blending, terminaling and storage operations over and above the value of the crude in the field. The value of the crude in the field can only be reliably estimated from such downstream sales if the market values of all of these services can be readily observed. Since this is rarely the case, estimating values in the production field from spot prices quoted for downstream transactions generally is fraught with error. In particular, failing to subtract the full value added by all downstream operations from the observed sales prices in these transactions results in overstating the value of the crude in the field and, hence, the lessees' royalty obligations.

A. The proposed methodology inappropriately attributes no cost or value to blending operations.

1. One example of a downstream cost that is completely ignored by the MMS methodology are the costs associated with blending crude oils. Crude oils are blended in California for a variety of reasons. For example, many heavy crude oils in California are too viscous to move easily through a pipeline. One option is to heat the pipeline to make the crude flow more easily. For example, TTTI's twenty inch pipeline that carries heavy crude from the San Joaquin Valley to San Francisco is a heated pipeline. These heated pipelines can be very costly to build and operate. Another option is to blend the heavy crude with lighter material so that the resulting stream can be moved in an unheated line. For example, Arco's Line 63 is an unheated pipeline that carries a mix of light and heavy San Joaquin Valley crudes to Los Angeles.

2. Other crudes are blended simply because there are many different crude fields in a particular area with widely varying characteristics but there are only a limited number of pipelines available to transport the crude to the refining centers. It simply makes more economic sense to build one pipeline to carry a blended stream from several different crude fields than to build a separate line from each field. Though the alternative uses of trucks or rail are also used substantially in California, these alternatives are more expensive if pipeline capacity is available.

3. Several firms in California, such as Texaco, have developed a substantial business of blending different crude oils. Much of this blending takes place at TTTI's Midway Station in the San Joaquin Valley. At Midway Station, TTTI blends several different crude oils (and sometimes natural gas liquids) in blending tanks in order to transport the crudes to Los Angeles on Lines 1 and 63 of the Four Corners Pipeline Company and to Texas on the All America Pipeline. These pipelines publish specifications for crude characteristics that shippers must meet in order to transport crude. For example, Line 63 requires that the API gravity of the crude be approximately 27 to 35 degrees and that the Reid vapor pressure be approximately 8 pounds per square inch. The goal of these blending businesses is to combine different crude oils, along with natural gas liquids and other light hydrocarbons, to meet these specifications at the lowest possible cost. These blending operations require full time employees as well as physical assets including crude oil and NGL truck unloading racks, storage tanks, four 30,000 barrel blending tanks with mixers, proprietary blending computer software programs, and other assets. This activity obviously requires real resources and incurs substantial costs. The MMS methodology completely ignores these costs and, hence, significantly overstates the lease value of the lessees' royalty crude.

4. In addition to ignoring the costs incurred by blending operations, the MMS also ignores the value these facilities add to the delivered crude price over and above their costs. This value is not necessarily a direct function of costs. Such value might arise because a firm's blending operations are very efficient and have low costs relative to other competing facilities. Alternatively, it could arise because the location or capabilities of particular facilities makes them uniquely valuable for strategic or other reasons. Regardless of the underlying source of the

value added by blending assets and operations, it makes no economic sense to include this downstream value added as part of the lease value of the crude on which royalties are calculated. Value arising from unique and valuable downstream operations would not be reflected in the price of the crude in the field, regardless of whether the producer sells the crude to a downstream affiliate or to an unaffiliated party.

B. The proposed methodology effectively treats all downstream marketing costs as costs necessary to put the crude in a "marketable condition." This makes no sense because Federal lease crude is typically in a "marketable condition" in the field.

1. It is important to clarify that the costs incurred by downstream transportation, blending, and marketing operations do not represent costs that must be incurred to put federal lease crude oil production into a "marketable condition". The existing regulations define marketable condition as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area."[4] The crude oil produced from federal leases is clearly in such a "marketable condition" in the field, before entering pipelines and blending facilities. This is demonstrated by the fact that many arm's-length sales, purchases and other arm's-length transactions occur in the producing fields. For example, TTTI has many contracts to purchase crude oil from other, non-affiliated producers from the same fields in which federal property is leased. Hence, Federal lease crude is clearly in a marketable condition in the field.

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[4] 30 C.F.R. § 206.101.

C. **The MMS errs in only permitting "actual costs" for transportation and not other costs and value added to be deducted from downstream prices. This leads the MMS to overstate the market value of the crude in the field and the lessees' royalty obligations.**

1. By only allowing deductions for transportation costs and making no allowance for other downstream costs incurred and value added including such things as the risks associated with price fluctuations and potential environmental liabilities that vertically integrated crude oil producers incur in moving crude, the MMS overstates the value of the crude that would be observed if the crude were sold in the field. As discussed above, economic analysis indicates that any economic rents accruing to the owners of transportation assets due to efficiency, strategic location or other unique aspects of the downstream assets will be reflected in downstream sales in competitive arm's-length charges for these services and not in the prices of crude oil sold in the field.

2. While the MMS regulations do contain provisions for limiting transportation allowances to certain "actual" transportation costs under very limited circumstances, MMS proposes to greatly expand the application of these provisions to virtually all production of an integrated company. The limited cost deductions contained in the regulations completely ignore or substantially understate the value of many downstream services and, hence, overstate the crude values which would result if the crude were sold in the field. For example, the existing regulations provide that transportation costs incurred by the lessee can be deducted from the gross proceeds in one of two ways. In cases where the lessee chooses to use downstream sales to value production at the lease, the transportation allowance shall be "based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment ... or a cost equal to the initial capital investment in the transportation system multiplied by a rate of

return in accordance with paragraph (b)(2)(iv)(B) ..."[5] MMS now proposes to require the lessee to use downstream benchmarks to value virtually all crude production at the lease.

3. Any deductions for transportation made pursuant to these provisions are likely to significantly understate the market value of downstream services provided by TTTI and other vertically integrated transportation companies and, hence, would overstate the price at which federal lease crude would actually sell for in the field. The proposed rule would likely overstate the value of the crude in the field for many reasons including the following: 1) The MMS approach is based on historical costs and frequently bears little relationship to current market values of transportation assets, and 2) downstream spot prices reflect other costs, risks and value added in addition to transportation.

4. For example, the depreciated historical cost of TTTI's pipeline assets which would be used under the MMS formula likely understates the current value of these assets, and hence, understates the appropriate deduction for capital costs. In addition to the increase in asset values due to inflation and general appreciation in land values, it would undoubtedly be far more difficult and costly to obtain the environmental and other approvals to build new pipelines in this corridor today than it was, for example, when Getty originally built the first pipeline in California running to the Bay Area in the 1960s.[6] Because of these factors, the TTTI pipeline (and other pipelines capable of carrying heavy crudes out of the San Joaquin Valley) are able to earn a return in the marketplace which exceeds the historical cost based return permitted under the MMS formula.

[5] 30 C.F.R. § 206.105.

[6] In particular, the risks and costs of dealing with any environmental problems due to spills or leaks on the line have greatly increased.

D. The use of downstream transactions by the MMS discriminates against vertically integrated producers and creates a disincentive for firms to make efficient downstream investments.

1. The MMS methodology of using "actual costs" to calculate transportation costs for vertically integrated crude oil producers effectively assumes that all value added by downstream operations would be reflected in the price of the crude in the field were it not for the fact that the producers internal accounting for transactions between the lessee and its downstream affiliate allows them to "shift" this value from the lessee to the downstream affiliate. In contrast, economic theory tells us that the price in the field would not reflect this downstream value added, even if the lessee had sold the crude to an unaffiliated third party. In a competitive market any profits that arise from valuable downstream assets such as efficient or strategically located pipelines or blending facilities will be earned by the company owning the downstream facilities and not the seller of crude in the field. This is true regardless of whether the parties are commonly owned or not. Hence, this value added is properly attributed to the downstream operations and not the lease value of the crude. When there are significant costs incurred and value added downstream of the field, it is not possible to conclude from any observed "premium" values calculated from downstream prices over the prices observed in the field that the sales price in the field does not represent market value.

2. Since the MMS's cost-based transportation deductions generally understate arm's-length crude availability and transportation charges, they imply that lessees that sell crude to vertically integrated transportation affiliates will generally pay higher royalties than lessees that sell identical crude to unaffiliated parties in the field. In effect, the MMS procedures are equivalent to their taking a share of the market value created by the downstream operations. If permitted, this policy would obviously have a detrimental impact on the willingness of Texaco and other vertically integrated firms to undertake efficient investments in downstream operations.

IX. Conclusions

1. The proposed regulations would substantially increase the amount of error in the crude oil valuation process. MMS proposes that we throw out the best information available on the value of crude oil in the field (actual arm's-length transactions that occur there) in favor of an extremely complicated and arbitrary procedure which offers little if any potential to more accurately value crude oils in the field.

2. Several aspects of the proposal are virtually certain to introduce large errors into the valuation process. For example, the proposal to maintain constant differentials between different crudes for a year at a time makes no economic sense. Relative crude prices can and frequently do change substantially even over short periods of time. Similarly, the use of "actual costs" to adjust for transportation will overstate the value of many crude oils in the field because it substantially understates or in some cases completely ignores a variety of other costs and risks that vertically integrated firms incur when moving crude from the field to downstream locations.

3. The high degree of uncertainty inherent in the proposed rule and the resulting discrimination against vertically integrated production and transportation firms will lead to inefficiencies and increased costs. Crude oil produced from the same field at the same time will be assigned different values depending on such factors as whether it is produced by a vertically integrated firm and how it will be disposed of downstream. This makes no economic sense. Similarly, by discriminating against vertically integrated firms, the proposed rule will reduce the incentives for many of these firms to make efficient downstream investments.

4. For these and the other reasons discussed above, I believe the prices in actual arm's-length transactions occurring at the lease provide a significantly more accurate and reliable measure of crude oil value than the proposed methodology.